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**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements. | Rulemaking 16-02-007 |

**ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PLAN AND RELATED COMMISSION POLICY ACTIONS**

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Attachment B: RESOLVE Inputs and Assumptions
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# ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PLAN AND RELATED COMMISSION POLICY ACTIONS

## Summary

This ruling and its attachments (chiefly, Attachment A) constitute the Proposed Reference System Plan, as originally conceived by Commission staff in the May 16, 2017 Administrative Law Judge Ruling which issued the Integrated Resource Planning (IRP) Staff Proposal for comment in this proceeding. The Proposed Reference System Plan is informed by modeling conducted by Commission staff and consultants in support of this proceeding in Summer 2017.

The Proposed Reference System Plan in this ruling contains a recommendation for the greenhouse gas (GHG) emissions target to use in the IRP process for the California electric sector, as well as for the load serving entities (LSEs) representing the portion of the electric sector under the Commission's authority. Ultimately, the California Air Resources Board (CARB) is required by Senate Bill (SB) 350 (DeLeón, 2015) to set these greenhouse gas targets for IRP, in consultation with the Commission and the California Energy Commission (CEC).

In addition, the Proposed Reference System Plan includes a recommended portfolio of electricity resources for the portion of the electric sector served by the California Independent System Operator (CAISO) portion of the California electricity grid. An associated GHG Planning Price, representing the marginal GHG abatement cost for the electric sector, as well as requirements for its use in planning, is also included. Finally, several recommended near-term Commission actions are included in this ruling.

Parties are invited to comment on this ruling, the questions embedded in it, all of its attachments, and the modeling analysis conducted to support it, by no later than October 26, 2017. Reply comments are invited by November 9, 2017.

## 1. Background

On May 16, 2017, an Administrative Law Judge (ALJ) ruling was issued attaching a Staff Proposal for the implementation of the IRP process at the Commission and for all LSEs under Commission authority. On June 28, 2017, over 50 parties filed comments in response to the IRP Staff Proposal. Over 30 parties filed reply comments on July 12, 2017.

In parallel, as proposed in the May 16, 2017 Staff Proposal, modeling analysis was conducted by Commission staff and consultants to help inform further steps in the implementation of SB 350 and its IRP components.

Preliminary results of this modeling were released publicly by staff on July 19, 2017, with an e-mail to the service list of this proceeding and the posting of materials on the Commission's web site. A full-day workshop for discussion with parties was then held on July 27, 2017. These were informal steps designed to advance understanding and discussion among parties in advance of the opportunity to submit formal comments.

This ruling represents the formal incorporation of the modeling results into the record of this proceeding via this ruling's attachments. Additional modifications to the modeling results and associated recommendations have been made to take into account the comments and reply comments from parties on the May 16, 2017 IRP Staff Proposal.

## 2. Modeling Analysis

Commission staff set up the design of the modeling work to reflect the range of GHG emissions expected to come from the electricity sector in 2030 in the Draft 2017 Climate Change Scoping Plan Update available from the CARB in January 2017.[1] At the time, based on CARB's economy-wide analysis of GHG emissions associated with abatement activities already planned or underway, the electric sector statewide was expected to emit between 42 million metric tons (MMT) and 62 MMT in 2030, under CARB's "Proposed Scenario."

While there were some differences between CARB's modeling approach utilizing the PATHWAYS model and the one undertaken by Commission staff for IRP purposes, in basic terms the top end of the CARB's range was similar to what would be expected from a 33% renewables portfolio standard (RPS) requirement and business-as-usual amounts of other clean resources including energy efficiency and storage, for example.[2]

The lower end of the range (42 MMT) represented full implementation of the RPS (at the 50% level) plus doubling of energy efficiency, as required by SB 350, in addition to reaching the Commission's storage requirements for LSEs, and the continued penetration of rooftop solar photovoltaics (PV) under the net energy metering (NEM) tariff. Generally speaking, there were some differences in the modeling treatment of excess procurement of RPS ahead of compliance targets (banked for use in future compliance periods) between the CARB modeling and RESOLVE modeling, the latter of which also involves a much more granular treatment of the electricity sector emissions overall.

To reflect the CARB Scoping Plan Proposed Scenario range, Commission staff originally proposed (in the May 16, 2017 IRP Staff Proposal) to model four

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[1] Draft available at: https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf.

[2] Additional documentation of CARB's modeling approach is available at: https://www.arb.ca.gov/cc/scopingplan/app_d_pathways.pdf.

scenarios of GHG emissions for the electric sector, including the high (62 MMT), middle (52 MMT), and low (42 MMT) end of the Scoping Plan electric sector GHG emissions range, plus an additional scenario constrained at 30 MMT of GHG emissions, specifically the level associated with CARB's Alternative 1 Scenario, to test what would be required to be delivered from the electric sector if, on an economy-wide basis, it was more cost-effective for additional GHG emissions reductions to come from the electric sector in 2030.[3]

Another difference between CARB and Commission assumptions that was discovered during the analysis was with respect to accounting for behind-the-meter combined heat and power facility emissions. CARB's methodology counts these emissions as part of the electric sector, while for Commission modeling purposes they were treated as industrial emissions. This results in an approximately 4 MMT difference in all scenarios, which should be kept in mind when comparing results.

Commission staff and consultants utilized the RESOLVE model, which is an electricity capacity expansion model, to begin to analyze these four levels of GHG emissions. The model starts by incorporating all existing (operating) and/or contracted electric sector supply resources (as of approximately October 2016), and then selecting the lowest cost additional resources from among a set of representative resources characterized by fuel, cost, and GHG emissions characteristics, among others, to meet the remaining load. Following is a list of the baseline resources reflected in the RESOLVE starting point, prior to optimization of any new resources.

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[3] See additional documentation in CARB's PATHWAYS output tool at: https://www.arb.ca.gov/cc/scopingplan/pathways_main_outputs_final_17jan2017.xlsm.

Demand-Side

- Energy Efficiency: CEC's 2016 Integrated Energy Policy Report (IEPR) Mid Additional Achievable Energy Efficiency (AAEE) + additional Assembly Bill (AB) 802 Efficiency – related to code baseline and behavioral impacts. These assumptions equate to approximately a 1.5x gain in energy efficiency by 2030.
- Behind-the-meter (BTM) solar PV: CEC 2016 IEPR Mid case (16 gigawatts by 2030)
- Demand Response: Existing demand response programs remain in place
- Electric Vehicles: CEC 2016 IEPR Mid case
- Building Electrification: CEC 2016 IEPR Mid case

Supply Side

- Diablo Canyon Power Plant: retired in 2024/25
- Once-Through Cooling (OTC) Plants: retired according to State Water Board schedule
- Other Thermal Plants: remain online throughtout the modeling period
- Existing Hydro & Pumped Storage: remain online throughout the modeling period
- Storage Mandate: full storage mandate of 1,325 megawatts (MW) achieved by 2024
- RPS Resources: existing and contracted resources, once online, remain online throughout the modeling period.

It is important to point out that the version of the model currently in use is only capable of optimizing primarily supply-side resources, including some distributed energy resources such as battery storage and some forms of demand response. Thus, energy efficiency, BTM PV, and more advanced forms of demand response still must be input as assumed baseline resources that are not further optimized by the model's resource selection algorithm. Commission staff has handled this by running several sensitivity cases with different levels of demand, to account for the range of possible penetration of these demand-side programmatic resources.

The selected renewable resource categories and geographic renewable resource potential, in particular, build upon a great deal of the previous work of Commission staff in the RPS proceeding developing the RPS Calculator. The RPS Calculator has been used in previous RPS and long term procurement planning (LTPP) proceedings to inform both long-term generation and procurement planning, as well as policy-driven transmission planning as part of the transmission planning process (TPP) at the CAISO.

Another important note is that the model is structured based on individual technologies and their cost profiles, layered on top of their operating attributes such as contributions to spinning reserves, ramping capabilities, etc. Therefore, some technologies are substitutable for each other (e.g., several tranches of battery storage can be substituted for long-duration pumped storage, albeit at different costs) to fulfill the system integration needs.

To make the model more user-friendly and to shorten run times, the model analyzes optimal portfolios for four representative years (2018, 2022, 2026, and 2030) rather than analyzing every year between now and 2030. In addition, the integration needs are analyzed on a representative sample of 37 days of the year, and not in all 8,760 hours individually. Thus, RESOLVE contains a simplified form of production cost modeling, while also simulating capital investment decisions. The goal is to make it more useful for the focus of the IRP analysis, which is capacity planning primarily for purposes of renewable integration and greenhouse gas emissions reduction.

After staff's initial analysis using RESOLVE, it became clear that implementing the 50% RPS requirement that is already in law, on its own, resulted in modeled electric sector emissions of approximately 51 MMT in 2030, before layering in any GHG emissions constraint. Since it appears, at this point in time, that there is a fairly widespread industry consensus that this level of RPS compliance is achievable and the state is on a path to achieve it, Commission staff elected to drop further analysis of the 62 MMT Scenario.

In addition, Commission staff recommended that the 50% RPS Scenario (constrained by the RPS requirement) become the default scenario against which other analyzed scenarios would be compared. It is important to note that this scenario also includes other statutory or regulatory requirements for storage, NEM, and demand response, but does not include a literal doubling of energy efficiency penetration in response to SB 350, in part because those energy efficiency targets are not yet adopted by the CEC, as required by SB 350 by November 2017. In addition, the Commission is currently considering the energy efficiency goals to be adopted for the investor-owned utility (IOU) service territories in the energy efficiency rulemaking (Rulemaking (R.) 13-11-005).

Because there is not yet an adopted energy efficiency target or widespread industry consensus, the Default Scenario includes energy efficiency estimates (affecting the demand forecast) at approximately 1.5 times the 2015 AAEE level as adopted in the 2015 CEC's IEPR demand forecast.

In summary, the three GHG Scenarios ultimately modeled by Commission staff and for which results were produced are:

- **Default Scenario:** reflects existing policies, notably the 50% RPS, which is equivalent to statewide GHG emissions of approximately 51 MMT.

- **42 MMT Scenario:** the low end of the electric sector range estimated by the CARB Scoping Plan.
- **30 MMT Scenario:** reflecting electric sector emissions in the CARB Scoping Plan scenario where there was no Cap-and-Trade program assumed (though it has since been extended). In this scenario, the electric sector contributes more emissions reductions through direct mandatory measures; the study of this scenario reflects the uncertainty about relative costs and interactions between sectors.

The latter two scenarios are constrained not by the RPS requirement, but instead by the GHG emissions levels statewide, scaled to reflect the footprint of the CAISO grid. Selected resources beyond those included in the baseline are then optimized by RESOLVE. The selected electricity resource portfolios and their associated costs are presented in the results for the 42 MMT and 30 MMT scenarios, with resources presented in comparison to the baseline resources, and costs presented in comparison to the Default Scenario. It should be noted that there are additional costs required to accomplish the Default Scenario relative to current conditions in the electric sector; those costs are assumed to occur in all scenarios and are not reflected in the relative cost reporting comparing scenarios to each other.

In addition to these three major scenarios, Commission staff ran the model with changes to over 30 individual variables to test sensitivity to specific resource cost and benefit assumptions.

Further, in addition to the numerous sensitivities, staff selected three particular resources to study in greater detail, because of their unique characteristics and the long lead times potentially necessary for their development. These analyses were done to further illuminate the potential value and risks associated with procuring these resources in the near term (next 1-3 years). They are:

- Pumped storage
- Geothermal
- Out-of-state wind.

To test the results related to these types of resources, staff manually forced the model to accept certain amounts of these resources in the earliest possible timeframes associated with their development timelines, to identify the impact on cost and value to the portfolio overall.

For all cases, total portfolio costs were estimated based on an incremental total resource cost metric, which is the measure usually used for estimating demand-side resource cost effectiveness. This metric takes into account fixed costs of new electric sector investments for generation and transmission, operating costs (including net purchases and sales), and utility and customer demand-side program costs. These costs are expressed in terms of annualized incremental costs over the course of the analytical time period (2018-2030) compared to the Default Scenario. Thus, the costs reported are not total costs, but rather total portfolio procurement costs, relative to the Default Scenario. Not included in the cost comparison are previously-authorized costs not related to resource optimization in IRP (e.g., distribution infrastructure replacement and upgrade costs, general and administrative costs, etc.).

### 2.1. Summary of Results

In general terms, to meet the Default Scenario, the RESOLVE model selects a small amount of wind and battery storage and larger amounts of utility-scale solar, by 2030. For the 42 MMT Scenario, the resource mix looks similar, with larger amounts of each resource chosen, plus a small amount of geothermal. In the 30 MMT Scenario, the resource mix in 2030 changes by adding, in addition to larger amounts of wind, solar, geothermal, and battery storage: pumped storage.

In no scenario does the model pick new natural gas plants to be built in the future. The simplicity of this statement, however, masks some additional underlying complexity in the modeling results that may affect the economics of operation of natural gas plants that should be further examined and that is further discussed later in this ruling.

The RESOLVE model is not designed to analyze individual natural gas plant dispatch impacts of various GHG constraints, because it handles categories or classes of plants and not individual plants by geography. However, Commission staff and consultants conducted some additional analysis to understand the impacts of the various GHG constraints on disadvantaged communities, both from a local air emissions and an economic development standpoint.

This additional analysis points out that a disproportionate number of existing natural gas plants are located in disadvantaged communities, as defined by those communities scoring in the top 25% according to the CalEnviroScreen Tool.

Staff suggests that the choice of the GHG Scenario (42 MMT vs. 30 MMT) has a greater impact on the air pollution emissions in disadvantaged communities overall than any of the sensitivities containing changes to individual variables. This is generally because reducing the emissions from the sector requires more reliance on renewables and less on natural gas, with combined cycle natural gas turbines being the most prevalent and largest emitters in the sector, since they run more hours than the peaking class of natural gas plants.

Similarly, the more stringent GHG Scenarios also resulted in a larger incremental renewable resource buildout in disadvantaged communities compared to the Default Scenario.

With respect to distributed energy resources (DERs), because most are not optimized intrinsically in the RESOLVE model, additional work is needed to be able to predict their value with specificity. But in general, several DERs generally reduced total costs, including energy efficiency, shift demand response (flexible loads), flexible charging of electric vehicles, short duration storage, and time-of-use rates. Other DERs typically increased total costs, including BTM solar PV and shed demand response, unless there are specific local capacity needs.

There are several major factors, beyond just the basic resource costs assumed, that drive these overall results. First, curtailment of renewables is an integration option in the model. Curtailment is modeled by assuming that the developer is paid its production cost regardless of whether its output is curtailed or delivered to the grid; this is consistent with the terms of most current RPS contracts. This curtailment alternative is lower cost than many of the more expensive renewable integration options for much of the time period analyzed. In the Default Scenario, the model predicts that curtailment would be approximately 3.2% by 2030, while it is 5.7% in the 42 MMT Scenario, and 7.3% in the 30 MMT Scenario. Staff also analyzed a "no curtailment" sensitivity, which shows that in order to avoid curtailment altogether, approximately 50 GW of storage would be required (in the 30 MMT Scenario) at a cost of nearly $3 billion per year.

Second, the ability to take advantage of the federal investment tax credits (ITC) and production tax credits (PTC) in the near term, before they expire, to purchase solar and wind resources, results in the model selecting these resources earlier than they would otherwise be needed for RPS compliance or reliability purposes, resulting in lower portfolio costs for ratepayers overall.  The expiration and/or renewal of the ITC and PTC would affect the optimal timing for purchasing additional solar and wind.

This also interacts with the timing of the replacement of the power from the Diablo Canyon nuclear plant, because, rather than waiting until the plant is retired (assuming that occurs), the model essentially chooses to pre-purchase the solar and wind power that would otherwise be needed later in the next decade, in order to take advantage of the cost savings associated with the ITC and PTC. In other words, the replacement power in the amount of Diablo output is already being replaced by GHG-free resources prior to the retirement of the nuclear plant.  And in all scenarios, the GHG emissions constraints in the CAISO area are met or exceeded.

Third, the modeling takes into account the amount of excess RPS procurement that has already occurred, particularly by IOUs, over and above the existing requirements, that can be banked and then used to demonstrate compliance in the future.  The use of this RPS procurement already banked has the effect of reducing the amount of additional renewable resources that are required to be developed in the future to meet a given GHG emissions target, at least for IOUs.

Fourth, new renewables in the modeling are not required to be fully deliverable with resource adequacy value, and may instead be paid on an energy-only basis.  The Attachment A slide deck contains details about the amount of fully deliverable renewable capacity would be chosen relative to energy-only resources.

Fifth, constraints on both import and export capability between California and other states in the West, including assumptions about utilizing existing transmission, may affect the assumed geography of renewable resource buildout. This is also true of renewable buildout within California. That is, assumptions about utilization of existing transmission within California can also affect the modeled renewable locations in California. These assumptions may or may not hold when actual procurement is conducted.

Finally, the model's assumption about the greenhouse gas emissions intensity of imports, which is based upon the value used by CARB in the Cap-and-Trade regulations, affects the predicted utilization of non-renewable resources within California between now and 2030, and results in a decrease in imports and an increase in California natural gas utilization, since the in-state plants generally have a lower emissions intensity. This may or may not reflect reality, depending on the trend over time in emissions produced by resources on the Western electricity grid overall.

In terms of costs relative to the Default Scenario, the 42 MMT Scenario is estimated by RESOLVE to cost approximately $239 million more per year, in 2016 dollars. For the 30 MMT Scenario, the additional annual costs are estimated at $1,137 million compared to the Default Scenario. The additional fixed costs are associated primarily with renewables and storage, with a small amount of additional transmission costs in the 30 MMT Scenario; cost savings are associated with the reduction in variable costs (primarily fuel costs).

The analysis was also designed to produce a RESOLVE output that estimates the marginal GHG abatement cost associated with a given GHG constraint. This number is referred to as the GHG Planning Price in the May 16, 2017 IRP Staff Proposal, and is designed to serve an objective planning function in the design of individual LSE IRPs. The GHG Planning Price is made up of the assumption about the Cap-and-Trade allowance price in each year (RESOLVE assumes a fixed Cap-and-Trade reserve price of approximately $29 per ton of GHG emissions in 2030) plus the incremental cost of reducing the marginal ton of GHG emissions to reach the GHG target constraint in the model.

The results of this analysis suggest that in 2030, the GHG Planning Price for the 42 MMT Scenario would be $150 per ton, while for the 30 MMT Scenario, the price would be $283 per ton.

These GHG Planning Prices are then proposed to become inputs to cost-effectiveness analyses currently under consideration in the Integrated DER proceeding (R.14-10-003). These results would replace the "interim GHG adder" values (including for avoided GHG, capacity, and RPS costs) adopted in Decision (D.) 17-08-022 for use in the avoided cost calculator, after the Commission renders a decision in this IRP proceeding.

With respect to the three resources selected by staff for special analysis (pumped hydro, geothermal, and out-of-state wind), the results suggest that out-of-state wind could represent a significant portfolio cost savings if procured prior to the expiration of the federal PTC. Early procurement of pumped hydro and geothermal, on the other hand, would tend to increase total portfolio costs based on current cost estimates.

### 2.2. Questions for Parties

1. Please comment on the appropriateness of the baseline resources included in the RESOLVE model. What changes would you make and why?
2. Comment on the appropriateness of the three major scenarios modeled by staff (Default Scenario, 42 MMT Scenario, 30 MMT Scenario).

3. Provide any comments or reactions to the cost metrics analyzed and the estimated cost results.
4. Comment on the viability of renewable curtailment as a grid integration strategy.
5. Comment on the advisability of early procurement of renewables to take advantage of federal ITC and PTC availability.
6. Comment on the impact of banked RPS procurement on this analysis.
7. Comment on the impact of import/export constraints on this analysis.
8. Comment on the results of the three long-lead-time resource studies summarized in this analysis:
   a. Pumped storage
   b. Geothermal
   c. Out-of-state wind

## 3. Electric Sector GHG Target

### 3.1. Staff Recommendation

In the slides attached to this ruling, Commission staff recommends the 42 MMT Scenario as the most appropriate target for IRP purposes. There are a number of reasons for this recommendation. First, it was originally chosen for analysis because of its relationship to the January 2017 Draft Scoping Plan Update of CARB. The Default Scenario, constrained by the 50% RPS, and representing the policy trajectory the electric sector is currently on, generally represents the status quo, business-as-usual expectation.

The 42 MMT Scenario represents increasing momentum from current policies, including renewables, energy efficiency, storage, and a number of other initiatives, to push the most emissions reductions out of the electric sector without creating unreasonable costs. Although it is a middle case among those analyzed, it represents an approximately 50% reduction in GHG emissions from the electric sector from 2015 levels. Recommending this case includes aggressive pursuit of reductions in the electric sector, while also encouraging exploration of more cost-effective emissions reduction opportunities from other sectors, especially transportation, where the electric sector can also play an important role.

Continuing on the path toward the Default Scenario overall may not provide enough market stimulation for the resource areas and markets that will be needed to achieve more aggressive goals in the future, such as energy efficiency, demand response, and storage, in addition to renewables.

More analysis is needed to pinpoint the trajectory required to get to the state's 2050 GHG target and the electric sector's contribution toward it, but it also appears as though the 42 MMT Scenario is roughly on the straight-line path toward this target, based on the PATHWAYS analysis conducted to inform CARB's Scoping Plan.

The 30 MMT Scenario, while it reduces GHG emissions further, it may do so at a higher near-term cost while overshooting the mark on the trajectory toward the 2050 GHG goal for the electric sector. Though information about the GHG mitigation costs in other sectors is limited, the more aggressive 30 MMT Scenario may also represent a disproportionate cost in the electric sector relative to other sectors, and it certainly represents a disproportionate share of emissions reduction responsibility relative to historical trends.

Staff does recommend that the 30 MMT Scenario continue to be studied, but that the LSEs' 2018 IRPs should focus on planning and procurement strategies to reach the 42 MMT Scenario.

### 3.2. Relationship to CARB and CEC Processes

The Commission is aware that the CARB Scoping Plan is undergoing revisions this year prior to being finalized for adoption by the Board, as a result of the recent passage of AB 398 (Garcia, 2017) which extends the Cap-and-Trade program authorization and requires that the Scoping Plan be updated. Because SB 350 requires the Commission to adopt an IRP process in 2017, Commission staff used the best available information from the January 2017 Draft Scoping Plan Update to identify the GHG emissions Scenarios to model for electric sector purposes.

The CEC is similarly working to provide guidance to the publicly-owned utilities in parallel with this Commission's requirements for LSEs. While the 42 MMT Scenario is the recommendation offered in this ruling for parties' comments, ultimately we hope to achieve consensus among all three agencies about a common planning assumption for the electric sector as a whole.

### 3.3. Questions for Parties

9. Do you agree with the recommendation to utilize the 42 MMT Scenario for IRP planning purposes? Why or why not?

## 4. Proposed Reference System Portfolio

### 4.1. Staff Recommendation

Since the 42 MMT Scenario is recommended as the preferred case for planning purposes for LSE IRP filings, the associated optimal resource portfolio is also recommended as the example portfolio against which the LSEs should compare their individual resource plans.

In 2030, the RESOLVE model selects an incremental set of resources, in addition to the baseline quantities of energy efficiency, demand response, storage, renewables, hydro, natural gas and nuclear, including the following (with the proportionate percentages of the total new resources selected by the model in parentheses):

- 200 MW of geothermal (1.6%)
- Approximately 9 gigawatts of utility-scale solar (73%)
- 1,100 MW of in-state wind (9%)
- 2,000 MW of battery storage (16.4%), incremental to the 1,325 MW already required, the need for some of which could be displaced by certain types of advanced demand response and/or pumped storage.

These results can also be characterized in terms of the overall resource portfolio that the model predicts will be serving CAISO load in 2030. In Table 1 below, the resource types are presented from two different perspectives. The first is the traditional supply-side approach where demand-side resources are treated as load modifiers, and only residual supply resources are presented. The second is a more integrated approach, where demand-side resources, instead of being subtracted from load, are treated as independent sources of supply, thus showing their contribution toward the overall electric system and toward serving the additional load that would have otherwise materialized absent demand-side programs.[4]

[4] It should be noted that electric vehicles do not fit neatly into this structure as a separate "resource" because they are treated as static load modifiers in the modeling, except for the sensitivities where flexible electric vehicle charging was explored. Thus, although RESOLVE cannot treat electric vehicles as batteries exactly, their impact would be analogous.

**Table 1. Proportions of Resource Types in Overall Proposed Reference System Portfolio by 2030**

| Resource type | Supply Resources Only | | Integrated Supply and Demand Resources | |
|---|---|---|---|---|
| | Energy | Capacity | Energy | Capacity |
| Natural Gas (including combined heat and power) | 36% | 34% | 28% | 27% |
| Nuclear | 2% | 1% | 2% | 1% |
| Hydro | 11% | 10% | 9% | 8% |
| Utility-scale renewables[5] | 43% | 41% | 33% | 32% |
| Storage[6] | 0% | 6% | 0% | 5% |
| Energy efficiency | NA | NA | 12% | 3% |
| Demand Response[2] | NA | NA | 0% | 2% |
| Customer PV | NA | NA | 10% | 16% |
| Imports | 8% | 8% | 6% | 6% |

### 4.2. Relationship to CEC's IEPR and CAISO's Transmission Planning Process

The Commission's LTPP proceedings have previously released, on a yearly basis, an Assumptions & Scenarios (A&S) document to memorialize a common set of assumptions and modeling methodologies to use in any

[5] It should also be noted that in no case does the utility-scale percentage appear to meet RPS requirements which are 50% in 2030, but this is misleading. In reality, the RESOLVE model ensures compliance with the RPS requirements, but two primary factors make it appear as though the requirements are not met: 1) the influence of imports in this table, which are not factored into the RPS compliance requirements according to RPS rules, and 2) the contribution of banked RPS procurement from prior periods that can be counted toward 2030 requirements but that do not necessarily result in RPS energy delivered in 2030. In addition, the separate designation of Customer PV resources makes the math more complicated, since these are effectively a subtraction from the total load, rather than a supply contribution.

[6] Storage and demand response have capacity value but no energy value. Storage may also be utility-scale or behind-the-meter. The RESOLVE model currently does not distinguish, but actual procurement would affect how the storage is counted.

long-term electricity system planning for California. In addition, the A&S has been the vehicle with which the Commission has coordinated with the CAISO on assumptions and planning portfolios for use in its annual TPP, as well as other Western electricity system planning entities. The A&S typically relies on outputs, such as the demand forecast, from the CEC's annual IEPR processes.

In past LTPP cycles, the draft A&S document has been issued via an ALJ ruling for comments from parties, with the final transmitted via an Assigned Commissioner Ruling from the assigned commissioner, with a transmittal letter to the CAISO.

For this cycle and subsequent cycles, we recommend that the A&S be replaced by the recommended Reference System Plan and associated documentation, for the policy-driven scenario. Specifically, the modeling assumptions and results associated with the Reference System Portfolio would be used for the TPP policy-driven scenario. The Default Scenario would be used for the TPP reliability base case studies, and would include a sub-set of the resources identified in the Reference System Portfolio.

As mentioned earlier, because RESOLVE utilizes existing transmission to the maximum extent possible to minimize costs, and actual procurement and development may deviate from this assumption, there may be a need to supplement the analysis with information from other sources. For example, the Renewable Energy Transmission Initiative (RETI) 2.0 effort has developed information with more land-use considerations than the RESOLVE analysis contains.

We seek comment on the recommendation to utilize the Default Scenario portfolio as the reliability base case and the Reference System Plan portfolio as the policy-driven scenario in TPP in this ruling. Because of the importance of these assumptions and scenarios for infrastructure planning, we intend, going forward, to bring the recommendations for TPP to the full Commission for adoption prior to forwarding to the CAISO. Once the Preferred System Plan is analyzed and adopted by the Commission, this would replace the Reference System Plan scenarios for the subsequent TPP cycle.

We recognize that there is a certain amount of technical judgment involved in translating the high-level Reference System Plan scenario recommendations into bus-bar level locational data for storage resources, demand response, additional achievable energy efficiency, etc. Therefore, this ruling recommends that the bus-bar level of data and assumptions be delegated to Commission staff to finalize and transmit informally, once the Reference System Plan portfolio and high-level scenario selection is endorsed by the Commission.

### 4.3. Questions for Parties

10. Do you support the use of the Reference System Portfolio associated with the 42 MMT Scenario as the model for LSE portfolio planning for their individual IRPs? Why or why not?

11. Do you support transmitting the Default Scenario and associated portfolio to the CAISO for use as the reliability base case in the TPP for 2018? Why or why not?

12. Do you support transmitting the 42 MMT Scenario and associated portfolio to the CAISO for use as the policy-driven case in the TPP for 2018? Why or why not?

13. Should the RETI 2.0 work or other available information be incorporated into the TPP recommendations for 2017? If so, how?

## 5. LSE Actions Acquired in Response to Reference System Plan

### 5.1. Staff Recommendations

Commission staff has a number of recommendations associated with actions that the individual LSEs should take in preparing their individual IRPs to be submitted in 2018.  In general, staff suggests that each LSE should file an IRP that adheres to the Reference System Plan guidance as closely as possible, as described further below.  In addition, each LSE may choose to include in its IRP a scenario or portfolio that deviates from the Reference System Plan guidance, but those deviations must be justified and explained.

#### 5.1.1. Use of GHG Planning Price

Commission staff proposes that the individual LSEs use the GHG Planning Price as a constraint in their individual IRP submittals.  If the GHG Planning Price is used as an input in the IRP process, as the marginal GHG abatement cost, each LSE should be able to identify a resulting portfolio with an estimated GHG emissions profile for its individual customer base and portfolio of owned or contracted resources.

In developing its portfolio, each LSE would add resources that reduce GHG emissions up to the point that the marginal cost of doing so equals the GHG Planning Price.  One approach is for LSEs to use the GHG Planning Price in lieu of the Cap-and-Trade allowance cost in calculating the marginal cost of GHG-emitting resources.  Then, if the LSE adds a resource that lowers the total portfolio cost (including cost of capital, fuel, etc.), the resource would be considered justified.  LSEs would continue adding resources until the cost of adding resources outweighs the benefits, or the total cost prevents the LSE from serving its customers reliably and at just and reasonable rates.

In addition, LSEs may also be motivated by factors other than cost. For example, to the extent that LSEs' future resource procurement plans reflect environmental, risk, and other factors not directly related to minimizing marginal costs, the LSE would describe its rationale in detail, with reference to all applicable state or local statutory requirements.

Essentially, each LSE should be willing to propose to buy any low- or zero-GHG resource at a cost that is less than the GHG Planning Price, and should describe the portfolio that would result from utilizing that assumption. Each LSE should also explain the relationship between that ideal portfolio, its existing portfolio, and any new resources required to be procured to make up any difference.

After validation and approval by the Commission as part of the development of the Preferred System Plan, this GHG emissions estimate associated with the LSE's proposed portfolio would become the LSE-specific GHG target for the individual LSE for the subsequent planning cycle.

Staff recommends that each LSE have two options for forecasting the annual GHG emissions associated with its portfolio:

1. The LSE may quantify direct and indirect GHG emissions for forecast years using methods consistent with the Energy Resource Recovery Account applications, specifically as instructed in Lines 1 through 12 in Template D-2 in Attachment D of D.15-01-024. That decision provides guidance on how to quantify emissions from different energy sources, including from utility-owned generation, unspecified energy imports, and contract and market purchases. The total emissions calculated for each LSE will be made publicly available.

2. Alternatively, if the LSE conducts capacity expansion or production simulation modeling over the IRP planning horizon, the LSE will be able to determine the resource composition of its portfolio, the ability of the resources in its portfolio to serve its

> own load in consideration of that load's underlying shape, and therefore its total fuel consumption or total market purchases. In that case the LSE should apply standard fuel emissions factors for estimating GHG emissions associated with those resources or market purchases. For estimating GHG emissions from unspecified imports, the LSE should use CARB's default emissions factor utilized in its cap and trade regulation.[7] For estimating GHG emissions from in-CAISO unspecified power, LSEs should use the GHG emissions factor associated with the portfolio selected for the Reference System Plan.

LSEs should indicate which new resources they anticipate procuring with reference to the four planning years modeled (2018, 2022, 2026, and 2030). For estimating the GHG Planning Price across these years, Commission staff proposes to project a straight-line increase beginning at the 2018 Cap-and-Trade Allowance Price Containment Reserve value (consistent with D.17-08-022) and increasing to the level of the 2030 GHG Planning Price of $150 per ton. This approach avoids having a relatively low GHG Planning Price value from 2018 to 2026 followed by a steep increase during the final few years of the planning horizon, which would increase the risk that cost-effective GHG-free investments are not realized by 2030.

It should also be noted that the purpose of the GHG targets, both for the sector as well as for individual LSEs, is for planning only. The Commission is not contemplating requiring after-the-fact compliance with the targets used for up-front planning. Compliance is intended still to be measured with respect to the individual programs which will support attainment of the GHG goal, including the RPS, storage mandate, energy efficiency goals, etc. In addition,

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[7] CARB's current figure is 0.428 MT of carbon dioxide equivalent per megawatt hour (MWh) or 943 lbs per MWh, but this figure may be updated in the future.

ultimately the Cap-and-Trade program is the compliance mechanism for the state for GHG emissions compliance purposes.

#### 5.1.2. Use of Reference System Portfolio

For individual LSE purposes, the primary use of the Reference System Portfolio would be the resulting proportionate capacity mix of new resources the model picks to be procured between 2018 and 2030. Secondarily, we would look to the overall proportionate mix of different types of resources, both existing and new, within the CAISO grid area, as a guide to the appropriate portfolio balance to achieve the 2030 GHG emissions target.

In conducting its individual planning, each LSE would take into account both the proportionate mix of new resources that the modeling suggests would be optimal, as well as the overall proportionate mix of resource types, in planning to serve its own load.

Each LSE will also be required to show its expected achievement of other statutory or regulatory requirements, such as meeting the 50% RPS, the storage mandate, the energy efficiency goals, the planning reserve margin, and all other such existing requirements.

If an LSE will need to procure new resources to serve its load, the LSE should propose a mechanism to acquire the needed resources, and explain the relationship between its proposed procurement and the optimal portfolio mix suggested by the Reference System Portfolio. If the LSE plans to deviate from the optimal resource mix suggested by the Reference System Portfolio, the LSE should explain why its unique circumstances or other factors make it prudent to do so, when filing its individual IRP.

### 5.1.3. Use of a GHG Emissions Benchmark

Commission staff acknowledges that while providing the Reference System Portfolio and GHG Planning Price as general guidelines affords LSEs flexibility in developing their own preferred portfolios, LSEs may also benefit from having more specific criteria by which they can assess the reasonableness of their GHG forecast estimates prior to the filing of their plans. For this reason, staff proposes that each LSE compare the emissions associated with its preferred portfolio against a Commission-assigned GHG Emissions Benchmark.

This benchmark would serve as a reference point by which both the LSE and the Commission can cross-check the LSE's use of the GHG Planning Price. Again, this is not intended as a compliance requirement and no enforcement is contemplated.

If the total emissions attributable to the LSE's preferred portfolio exceed its GHG Emissions Benchmark for 2030, the LSE would be required to explain the difference and describe additional measures it would take over the following 1-3 years to close the gap, along with the cost of those measures. If the gap is significant, the Commission may require the LSE to modify its plan.

The GHG Emissions Benchmark is proposed to be calculated in two steps. First, Commission staff would divide the 2030 GHG planning target for the electric sector among Commission-jurisdictional electric distribution utilities (EDUs) based on CARB's draft methodology for the 2021-2030 allowance allocation under the Cap-and-Trade program, similar to the how the electric sector target is divided between the Commission's and the CEC's respective IRP processes.

Next, staff would further divide that value proportionally among the host EDU and non-EDUs (community choice aggregators and electric service providers (ESPs)) within the host EDU's territory based on their projected 2030 load shares. The resulting value would become the LSE's assigned GHG Benchmark for IRP planning purposes.

Because ESP load forecast information (consistent with IEPR Confidential Form 8.1a) is considered confidential, the GHG Emissions Benchmark would be determined for all ESPs in aggregate within each IOU service territory, and these top-level values would be made public. However, each ESP would be required to calculate its own confidential GHG Emissions Benchmark using the formula outlined above, and to use that benchmark in developing is individual LSE IRP.

#### 5.1.4. Relationship to Planned Procurement

As discussed above, both the optimal portfolio represented by the Reference System Portfolio and the GHG Planning Price should inform any planned procurement by individual LSEs.

When proposing to conduct procurement to acquire certain resources, each LSE should propose the type of procurement it intends to conduct within the following three years after the plan is filed. Planning for procurement for up to three years will allow for overlap with the subsequent IRP planning cycle, so that the prior approved procurement, if any, can still be conducted while subsequent procurement is being planned. For example, an IRP filed in early 2018 could propose procurement activities in 2018, 2019, and 2020. The IRP filed in 2020 could then propose additional procurement in 2020, 2021, and 2022. And so on.

In addition, we would expect that each LSE would take into account the lead time required for the development of each of its preferred resources when determining the timing of its activities. For example, if a resource needs an estimated seven years to come online and is needed in 2025, it would need to be represented in the LSE's 2018 IRP filing.

In addition, the expectation for this IRP cycle is that the IOUs would continue to file and/or update bundled procurement plans, as needed, though this could change in the future as everyone gains more experience with the IRP filing and approval process.

#### 5.1.5. Cost and Ratepayer Impact Analysis

Among other requirements, Public Utilities Code Section 454.52 requires that the IRP process "enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates" and that all LSEs should seek to "minimize impacts on ratepayers' bills."

All of the Commission's IRP analysis thus far has been structured around meeting GHG emissions constraints and system reliability needs at the lowest possible cost. We expect this approach to continue throughout the individual LSEs' IRP processes. All LSEs should consider cost and rate impacts on their customers when planning and submitting their individual IRPs, and, at a minimum, include a narrative description of their approach in support of this requirement.

Specifically for electrical corporations or IOUs, staff proposes that each IOU filing a Standard IRP Plan provide a revenue requirement forecast through 2030 for costs as captured in the LSE's portfolio that is responsive to the direction in the Reference System Plan and the LSE's preferred plan (if they are different). This revenue requirement forecast would include any impacts on distribution, transmission, generation (including conventional, renewables, and storage), demand-side programs, and other any impacted costs. The costs would be forecast consistent with the categories covered by each IOU in its general rate case.

In addition, each IOU would also be required to submit a system average rate forecast for each portfolio (the Reference System Portfolio and any IOU preferred portfolios) through 2030, utilizing the load forecast from the most recent IEPR.

#### 5.1.6. Treatment of Disadvantaged Communities

Staff also proposes that each LSE be required, in its IRP, to describe the disadvantaged communities it serves, as well as the manner in which the LSE plans to meet the requirements of SB 350. In particular, each LSE must describe how it will plan for early priority on disadvantaged communities both for reducing GHG emissions (and associated local air pollutants) and for increasing local economic development opportunities for clean energy. Each LSE should also be required to describe its evaluation criteria for resource selection during the procurement process, if procurement is proposed, with factors addressing issues of concern in disadvantaged communities.

### 5.2. Questions for Parties

14. Do you support the staff recommendation for how LSEs should utilize the GHG Planning Price in preparing their individual LSE IRPs? Why or why not?
15. Do you support the staff recommendation for how LSEs should utilize the Reference System Portfolio in preparing their individual LSE IRPs? Why or why not?
16. Do you agree with the above-described relationship between the Reference System Portfolio and the GHG Planning Price? Why or why not?
17. Do you support the staff recommendation for calculating and assigned a GHG Emissions Benchmark for LSEs to use in preparing their individual LSE IRPs? Why or why not? Would you recommend an alternative means of developing a similar benchmark? Explain.

18. Do you support the staff recommendation for requiring IOUs filing Standard IRPs to submit revenue requirement and system average rate forecasts to evaluate the impact of IRP costs on ratepayer costs of the IRP process? Why or why not?
19. Are there additional components that would need to be explored in order to develop a more comprehensive approach to conducting ratepayer impact analysis in later IRP cycles, for both IOUs and other LSEs? Explain.
20. Do you agree with the proposed requirements for LSEs to address the impact of their IRPs and any planned procurement on disadvantaged communities?

# 6. Commission Policy Actions

## 6.1. Staff Recommendations

As a result of the analysis conducted to inform this ruling and its attachments, Commission staff has identified several areas that would benefit from further work and/or action steps from the Commission itself, to support achievement of the recommended GHG target for 2030 in the electric sector. This section details those action areas and seeks parties' comments on the proposed policy actions of the Commission.

### 6.1.1. Renewables Requirements

Because all of the scenarios, including the recommended 42 MMT Scenario, contemplate additional procurement within the CAISO area of wind and solar in the near term (prior to 2022), primarily to take advantage of the availability of the federal ITC and PTC prior to expiration, there are several possible steps that the Commission could take to encourage this additional procurement.

One concrete action that the Commission could take to ensure additional near-term procurement of wind and solar resources would be to raise the RPS compliance requirement for all LSEs. One option would be to have the

Commission order a higher RPS level in this proceeding as a result of the IRP analysis; another would be for the Commission to consider ordering this outcome, and associated compliance activities, in the RPS rulemaking.

A second action the Commission could take would be to order additional renewable procurement in the IRP proceeding, outside of (in addition to) the RPS compliance context. This would imply additional renewable procurement requirements, perhaps without associated pre-existing RPS compliance requirements.

#### 6.1.2. Out-of-State Wind

In addition, from the resource-specific analysis conducted by staff for out-of-state wind resources, it appears as though some ratepayer cost savings, as well as resource diversity benefits for renewable integration, could be achieved by procuring more out-of-state wind resources in the near term. Achieving this outcome would require targeted examination of options for accelerating the development of transmission to support delivery of additional wind from out of state.

If out-of-state wind resources are procured through existing RPS mechanisms, some opportunities may also be constrained by the portfolio content category ("bucket") requirements for simultaneous delivery of energy and renewable attributes into the state.

To further options associated with the potential for accelerating procurement of out-of-state wind, Commission staff proposes to work closely with the CAISO to examine the possibilities for transmission development to facilitate wind imports. Development of additional transmission may also benefit the current constraints on imports and exports generally; these constraints have direct impacts on the results of the scenarios already modeled.

One option to direct further analysis of the out-of-state wind and associated transmission would be to transmit the special portfolio modeled for this purpose to the CAISO for a "special study" under its TPP, or in addition to it, for 2018. A special study analysis would not result in transmission investments in this TPP cycle, however.

Thus, a second option would be for the Commission to transmit a request for the study of out-of-state wind options as part of the policy-driven scenario for the TPP, in order to allow for study of transmission investments that could be approved before 2020. In order to accomplish this, additional analysis would be required to identify the geographic areas to be studied based on the likely renewable portfolios, since the RESOLVE analysis so far was constrained by a lack of detailed information about the most cost-effective combinations of new transmission infrastructure and wind resources.

#### 6.1.3. Integrated Distributed Energy Resources Cost-Effectivenss Analysis

Commission staff proposes to utilize the GHG Planning Price as a replacement to the GHG adder recently adopted in D.17-08-022 in the integrated DER (IDER) proceeding. The most straightforward manner in which the GHG Planning Price could be used as an avoided cost input is to project a straight line increase in the GHG adder beginning at the 2018 level adopted on an interim basis in D.17-05-022 and increasing to the level of the 2030 GHG Planning Price suggested by the chosen GHG Scenario in the IRP proceeding.

#### 6.1.4. Development of a Common Resource Valuation Methodology

Establishing a clear link between planning and procurement activities is an important part of the IRP process. A common resource valuation methodology (CRVM) that captures the resource valuation attributes as defined in IRP modeling so that they can be reflected in procurement activities and bid evaluation could help provide this link.

Commission staff proposes to work together with stakeholders to develop a CRVM proposal to ensure that the costs and benefits used in IRP planning are reflected in bid evaluation and program funding authorization across resource types. Scoping of this work would begin in late 2017, with a phased approach that prioritizes CRVM development for resource areas that are likely to see procurement activity in response to the 2017-18 IRP. For example, renewable procurement is likely, and the RPS program already contains a requirement for least-cost best-fit evaluation that is analogous to the CRVM concept.

#### 6.1.5. Natural Gas Fleet Impacts

The modeling results show that, other than the OTC plant retirements, the other natural gas resources already delivering energy to the CAISO are needed for reliability and renewable integration purposes through 2030 to reduce overall system costs. Keeping existing gas capacity available is predicted as more cost-effective than retiring gas plants and acquiring new ones, or alternative replacement capacity, to serve reliability and integration needs.

However, because the RESOLVE model handles classes of resources and not individual plants, and because the expiration of the ITC and PTC would drive early procurement of solar and wind resources, lowering utilization of the natural gas capacity in the near term prior to retirement of the Diablo Canyon nuclear plant in the medium term, more analysis is needed to identify the types of gas plants, or plant attributes, that are most desirable and most needed for reliability. Further work is also needed on how to design procurement or contractual mechanisms to support sustaining the desirable natural gas plants and characteristics in the near and medium term to support attainment of the 2030 GHG target sector wide at least cost while maintaining reliability.

This is another area of study where collaboration with the CAISO will be important. Commission staff proposes to work with the CAISO to study options for ensuring ongoing viability for renewable integration and resource adequacy/reliability purposes.

### 6.2. Questions for Parties

21. Should the Commission raise the RPS compliance requirement for 2030 and/or intervening years for all LSEs?
    a. If so, to what percentage?
    b. If so, in this proceeding or as a recommendation to be considered in the RPS rulemaking (or another venue: please specify)?
22. Should the Commission require additional renewable procurement outside of the RPS program?
    a. Why or why not?
    b. If so, how?
    c. If so, at what level?
    d. If so, from whom?
23. Should the Commission initiate activities with the CAISO or others to investigate further development of out-of-state wind?
    a. Why or why not?
    b. If so, what specific steps should be taken?
    c. Should out-of-state wind be included in a special study or as part as a policy-driven scenario for TPP? Why or why not?
24. Should the Commission utilize the GHG Planning Price as an input to the IDER avoided cost calculator, as described in this ruling?

a. Why or why not?

b. Do you have specific recommendations for the appropriate methodology for use of the GHG Planning Price in IDER or other demand-side resource proceedings/activities? Describe in detail.

25. If the Commission were to engage in development of a CRVM:

a. What resource areas should be prioritized for incorporation into the CRVM?

b. Do you have specific recommendations for the appropriate structure of a CRVM? Include examples from other jurisdictions where possible.

c. What would be the appropriate application of such a method?

26. Should the Commission initiate activities with the CAISO or others to analyze the type and viability of the natural gas fleet? What activities should be undertaken and why?

## 7. Resource Policy Coordination

### 7.1. Staff Proposal

The "Path to Future All-Resource Planning" in Attachment A is intended to demonstrate a path for the logical evolution of the IRP process within and across cycles, vis a vis other affected resource proceedings and planning processes, particularly to facilitate comprehensive optimization of all resources in future IRP cycles. These slides represent a culmination of process alignment activities with internal Commission stakeholders representing the highlighted resource areas and proceedings. The slides are meant to articulate a logical path from conclusions of the IRP modeling to the associated implications and action items that might flow from them.

Commission staff intends to build on these action items and associated party comments to develop a work plan that will facilitate a more comprehensive optimization of all available resources in the next IRP cycle.

### 7.2. Questions for Parties

27. Please comment on the slides in Attachment A titled "Path to Future All-Resource Planning" with respect to the following:
    a. Are any of the conclusions, implications, or action items inappropriate? If so, how would you amend them?

Are any conclusions, implications, or actions missing that the Commission should consider? Explain.

## 8. Production Cost Modeling-Related Issues

### 8.1. Staff Proposal for Production Cost Modeling to Support IRP

The May 16, 2017 IRP Staff Proposal, in Chapter 5, contained a general outline of production cost modeling steps that the Commission staff proposed to take to review the individual LSE Plans. Attachment E to this ruling contains a more developed and comprehensive proposal to utilize production cost modeling, both for evaluating the Reference System Plan and portfolio recommendation, as well as for evaluating the collection of individual IRP filings in order to recommend the Preferred System Plan. This proposal was also preliminarily discussed at a staff-hosted webinar meeting of the Modeling Advisory Group on September 6, 2017.

In particular, staff recommends the use of the Strategic Energy Risk Valuation Model (SERVM) to conduct production cost modeling of the system portfolios being considered in the IRP process. The primary purpose of this modeling is to evaluate the system reliability and performance of both the Reference System Plan and Preferred System Plan portfolios in higher operational detail and under a wider distribution of conditions than were considered in RESOLVE modeling. Because the SERVM model is already used in the Commission's Resource Adequacy proceeding, staff believes it is reasonable and efficient to leverage that production cost modeling experience for use in the IRP process. In addition, staff believes that the insights gained from the California Energy Systems for the 21$^{st}$ Century (CES-21) research project described below may be useful for enhancing IRP production cost modeling activities in the current or future IRP cycles. The CES-21 project also used the SERVM model and investigated very similar questions to those that the IRP production cost modeling activities seek to answer.

### 8.2. California Energy Systems for the 21$^{st}$ Century Grid Integration Project Results and Recommendations

On August 15, 2017, Commission staff hosted a workshop for presentation of the results of the CES-21 research and development program study on grid integration flexibility metrics and standards. CES-21 is a public-private collaborative research and development program between the large electric IOUs and Lawrence Livermore National Laboratory to address the challenges of cybersecurity and grid integration. The program was authorized by Commission Resolution E-4677.

The CES-21 Grid Integration project objective was to examine and recommend planning metrics and standards that explicitly consider operational flexibility. The project built upon the last few years of modeling experience in the LTPP proceedings and was designed to help the Commission evaluate and address future reliability challenges potentially posed by higher renewables penetration. The study aligned its assumptions with the standard planning assumptions described in the May 17, 2016 Assigned Commissioner's Ruling in

R.13-12-010 (the previous LTPP proceeding). However, the CES-21 Grid Integration project, being a research project, was never intended to produce results that could inform procurement in any way. The primary intent was to develop a more robust analytical framework for measuring the reliability and operational flexibility of a system like the CAISO balancing area, given an assumed high renewable mix of resources.

The CES-21 Grid Integration project filed its final report in this proceeding (the LTPP successor) on September 12, 2017 and served the report on the service list. In accordance with the requirements of Resolution E-4677, interested parties in this proceeding are invited to comment on the report's findings and recommendations in response to this ruling.

### 8.3. Questions for Parties

28. Please comment any aspect on the staff proposal included as Attachment E to this ruling. Explain the reasoning behind any recommended revisions. Please organize your comments according to the major topics of the proposal.

29. Please comment on the results and recommendations from the CES-21 grid integration project final report filed on September 12, 2017 in this proceeding. Note that the CES-21 project is complete and is not seeking comment to conduct additional work. The Commission seeks comment on:

    a. the technical merits of the analytical framework used in the CES-21 project

    b. what aspects of the CES-21 project (e.g., directional findings or recommendations, or the modeling techniques) can be used to improve the staff proposal in Attachment E, in the current or future IRP proceedings, and how.

## 9. Next Steps and Schedule

On August 24, 2017, Commission staff made an offer to the service list of this proceeding to run some additional RESOLVE cases at the request of parties in the proceeding, for parties who are unable to run the analyses on their own. Parties were asked to submit requests for cases to be run no later than 5:00 p.m. on the fifth business day after the release of this ruling. Staff then offered to post to the Commission's web site approximately five days later a list of the final cases that will be run by staff; the results will then be published informally on the web site approximately ten days' after the request deadline.

This offer was made as a courtesy to assist parties in preparing comments on this ruling and its attachments. In order for the Commission to consider on the record of this proceeding any additional results prepared by staff in response to these requests from parties, those parties wishing to refer to the additional cases and results should actually attach the results produced and posted by staff to their filed comments. Attaching the results materials directly is necessary in order for the Commission to be able to consider this evidence on the record and is in addition to parties referring to or commenting on the results in their prepared comments.

Parties filing and serving comments are requested to organize their comments in the same order as and with reference to the questions in this ruling, even if a party chooses not to answer all questions. Parties are also free to comment on any other aspects of the ruling and/or its attachments not specifically included in the questions above; those additional comments should follow the responses to the numerical questions. There is no page limit on the length of comments or reply comments.

Parties may file and serve comments by no later than October 26, 2017. Reply comments may be filed and served by no later than November 9, 2017.

To facilitate parties' understanding of the recommendation in this ruling and its attachments, as well as to discuss feedback from stakeholders, Commission staff plan to host a two-day workshop on September 25-26, 2017. Further details about the workshop will be posted to the Commission's Daily Calendar and shared with the service list of this proceeding.

These activities are summarized in the table below, with expected timeframes.

| **Activity** | **Expected Timing** |
|---|---|
| Release of Proposed Reference System Plan ruling (this ruling) | September 19, 2017 |
| Party requests for additional RESOLVE cases to be run, due to Commission staff | September 26, 2017 |
| Workshop on Proposed Reference System Plan | September 25 and 26, 2017 |
| Results of additional cases posted in response to requests from parties | October 6, 2017 |
| Comments due in response to this ruling | October 26, 2017 |
| All-party meeting with Commissioners | November 2, 2017 |
| Reply comments due in response to this ruling | November 9, 2017 |
| Proposed Decision issued | End of 2017 |
| IRP guidance transmitted to CAISO and CEC for TPP and IEPR purposes for 2018 | Early 2018 |
| IRP filings by individual LSEs | Q2 2018 |
| LSE IRPs adopted or modified by Commission | End of 2018 |
| IRP guidance transmitted to CAISO and CEC for TPP and IEPR purposes for 2019 | Early 2019 |

**IT IS RULED** that:

1. The modeling results and all attachments to this ruling are hereby entered into the formal record of this proceeding.

2. Parties may file and serve comments in response to this ruling by no later than October 26, 2017. Parties should respond to the numbered questions throughout this ruling with reference to specific question numbers. Comments on any and all other aspects of any of the ruling or its attachments may follow.

3. An all-party meeting is hereby noticed for November 2, 2017 in the Commission Auditorium in San Francisco beginning at 9:30 a.m. A quorum of Commissioners may attend, along with advisors and Administrative Law Judges. No decisions will be made and no votes will be taken.

4. Parties may file and serve reply comments on this ruling and its attachments by no later than November 9, 2017.

Dated September 19, 2017, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge